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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas And Electric Company (U 39-E) for Approval of 2008-2020 Air Conditioning Direct Load Control Program	Application No. A. 07-04-009 (Filed April 6, 2007)

MOTION OF THE UTILITY REFORM NETWORK FOR ADMISSION OF ITS LATE-FILED TESTIMONY INTO EVIDENCE

TURN
affordable utilities
livable communities

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November 6, 2007

MOTION OF THE UTILITY REFORM NETWORK FOR ADMISSION OF ITS LATE-FILED TESTIMONY INTO EVIDENCE

TURN filed its opening brief in A.07-04-009 on October 29, 2007 but neglected to attach the public version of its testimony. As per the directions of ALJ Bemesderfer via telephone conference on November 5, 2007, TURN submits its testimony concurrent with this motion to admit the testimony into evidence.

TURN does not believe that any party will be prejudiced by TURN's late-filed public testimony as TURN served this testimony upon all parties on September 17, 2007. TURN therefore requests that the Commission adopt the attached Proposed Order.

November 6, 2007

Respectfully submitted,

________/S/__________________

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VERIFICATION

I, Nina Suetake, am an attorney of record for THE UTILITY REFORM NETWORK in this proceeding and am authorized to make this verification on the organization's behalf. The statements in the foregoing document are true of my own knowledge, except for those matters which are stated on information and belief, and as to those matters, I believe them to be true.

I am making this verification on TURN's behalf because, as the attorney in the proceeding, I have unique personal knowledge of certain facts stated in the foregoing document.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on November 6, 2007, at San Francisco, California.

/S/
Nina Suetake
Staff Attorney

ATTACHMENT

Proposed Order

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas And Electric Company (U 39-E) for Approval of 2008-2020 Air Conditioning Direct Load Control Program	Application No. A. 07-04-009 (Filed April 6, 2007)

PROPOSED ORDER

The Motion of The Utility Reform Network for Admission of Its Late-filed Testimony into Evidence is granted.

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Administrative Law Judge

Analysis of PG&E's Proposed Direct Load Control Program

Prepared Testimony of
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On behalf of
The Utility Reform Network

California Public Utilities Commission
A. 07-04-009

September 17, 2007

Public Version

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Testimony of The Utility Reform Network in PG&E's Application for an Air Conditioning Direct Load Control Program

I. Introduction

This testimony is presented on behalf of The Utility Reform Network (TURN) by Jeffrey A. Nahigian, Senior Economist with JBS Energy, Inc. Mr. Nahigian has over 20 years experience working on energy issues and has appeared before this Commission on numerous occasions. His qualifications are contained in Attachment A.

TURN does not support PG&E's proposed load control program as filed in this case. TURN generally supports residential direct load control (i.e., air conditioner cycling) because these direct load control programs have the ability to provide some of the most reliable and cost-effective demand response available from the residential class. Unfortunately, PG&E has managed to design a residential load control program that, by its own admission, is not cost-effective, even under PG&E's alternative scenario that accelerates its need for new capacity resources—relative to PG&E's base case analysis.

Despite PG&E's poorly designed program, TURN believes that the program can be designed cost-effectively. Accordingly, TURN devotes this testimony to designing a residential direct load control program that has the potential to actually provide PG&E's ratepayers with a cost-effective program to reduce residential air conditioner loads during times of system stress. Because the program was originally designed in such a poor manner, it is necessary for the Commission to adopt virtually all of TURN's recommended adjustments to this program to ensure that program benefits exceed program costs.

In the alternative, if the Commission does not adopt all of TURN's adjustments, TURN recommends that the Commission order PG&E to issue a new RFP to completely outsource to a third party the design, installation, and full implementation of a residential direct load control program—similar to the agreement SDG&E has with Comverge. As part of issuing that new RFP, the Commission should order PG&E not to accept any programs that cannot be demonstrated to be cost-effective relative to PG&E's value of new capacity—since it is not in PG&E ratepayers' interests to fund non-cost-effective demand response programs regardless of whether those programs are administered by the utility or by a third party.

II. PG&E's Proposed Direct Load Control Program

A. General Description

PG&E proposes a direct load control program targeted to both residential and small commercial customers (under 200 kW). It proposes to give targeted residential and/or small commercial customers the choice of installing either an air conditioner cycling Switch (Switches) or a programmable communicating thermostat (PCTs). PG&E forecasts that it will install approximately 400,000 devices load control devices—85% of these devices will be installed on residential customer premises and the remaining 15% of the devices will be installed in small commercial premises with 90% of those installed for small commercial customers with loads less than 20 kW and the remaining 10% installed for commercial customers with loads between 20kW and 200 kW. PG&E forecasts that—given the choice between PCTs and AC Switches—60% of program participants will choose a PCT and the remaining 40% will choose Switches. PG&E proposes to install load control devices in the 2008-2010 and forecasts it will obtain 305 MW of demand response by 2011.

Program participants would receive a one-time payment up to $50 (residential) and $100 (small C&I) for enrolling in either the Switch or the PCT program.[1] PG&E does not propose to include an annual incentive payment, but instead, anticipates that it may offer an end-of-summer token gift or prize to express the utility's appreciation to customers for participating in the program. PG&E reasons that most participating customers will value issues such as helping the environment and ensuring power reliability over modest incentive payments. It also reasons that setting an initial [higher] incentive value will also set customer expectations (PG&E, p. 2-11).

PG&E proposes to operate its residential PCTs on an incremental adjustment (1 degree per hour), up to four degrees over the event duration. For customers choosing Switches, residential customers will be cycled on a 50% basis (15 minutes over each 30 minute interval) and small commercial customers will be cycled on a 33% basis (10 minutes over each 30 minute interval).

PG&E proposes to limit the number of load control hours to 100 hours per year and six hours per day. Customers will have the ability to override interruptions; however, they will be required to do this either by phone or through the Internet. While PG&E would generally dispatch this program a) during, or in anticipation of, a Stage II event or b) when a critical peak-pricing (CPP) event is called it also proposes that it be allowed to use a "soft trigger" dispatch for other unforeseen events.

B. PG&E Assumptions on Demand Impacts Per Customer

PG&E forecasts that it will receive 1.1 kW of average hourly demand reduction for both residential Switches and residential PCTs. For small commercial (below 20 kW) PGE& anticipates a 0.88 kW average hourly reduction for PCTs and a 1.12 average hourly demand reduction from Switches. For commercial customers with loads of 20 kW to 200 kW, it expects an average

[1] PG&E states that it will begin with an initial $25 installation incentive and adjust it either upward or downward depending on the customer interest level (PG&E, p. 2-11).

hourly demand reduction of 1.54 kW for PCTs and 1.96 kW reduction from Switches (PG&E, Table 4-3, p. 4-13).[2]

PG&E proposes to allow both residential and small commercial customers participating in its direct load control program to also take service under critical peak pricing (CPP) tariffs. PG&E forecasts that by 2011 close to 30% of its direct load control residential customers will also take service under CPP tariffs and 18% of its small commercial customers will have an overlap of CPP rates and direct load control (PG&E, pp. 4-14 and 4-15). Because of this PG&E provides its assumptions (for customers served both on a CPP rate as well as participating in its direct load control program) that divide and attribute demand savings to a) CPP versus b) direct load control. These assumptions are explained in Table 4-4 for residential air conditioning customers that also take service under critical peak pricing tariffs.

To put this analysis in simple terms, PG&E assumes that the demand savings resulting from a customer (served under existing tariffs) participating in its direct load control program can be entirely attributed to the direct load control program, while the demand savings associated with a customer that is served under CPP rates must be split between demand savings resulting from CPP and demand savings resulting from the direct load control program. The result is that less demand savings is credited to the direct load control program for participating customers on CPP than for participating customers not on CPP.

In addition to this adjustment, PG&E makes a number of other adjustments to demand impacts per customer. PG&E assumes annually that 0.5% of active sites will have malfunctioning technology, 2% of the Switch installations

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[2] These assumptions concerning demand savings per unit are reported prior to PG&E other adjustments for program attrition, equipment operation, and CPP program participation.

will be inadvertently disconnected, and 8% of its customers will actively override the technology during an event.

PG&E's testimony generally states that installing approximately 400,000 units will result in approximately 300 MW of incremental load control over the 2008-2010 period. Specifically, PG&E's workpapers show that it assumes (after the adjustments described in the preceding paragraphs) that installing close to 380,000 load control units (both PCTs and Switches for both residential and small commercial customers) will provide 305 MW of available direct load control.[3]

C. Equipment and Installation Costs

PG&E proposes to spend $ [redacted] per unit for residential air conditioner Switches and $[redacted] per unit for each small commercial Switch. PCTs will cost over double this amount or $[redacted] per residential PCT and $[redacted] per small commercial Switch. PG&E also proposes to spend $[redacted] per unit to install AC Switches and $[redacted] per unit to install PCTs. The utility forecasts market acquisition costs will amount to $[redacted] per residential customer and $[redacted] per small commercial customer. Other costs included in the program include call center operation costs, shop testing, measurement and evaluation, system integration costs, software licensing and maintenance as well as project management costs.[4] In addition to these program costs, PG&E seeks authorization to charge ratepayers a "risk-based contingency allowance" of $19.437 million.

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[3] The additional 5 MW above the 300 MW is attributed to the currently authorized 2007 program that has a target of 5 MW by the end of 2007.

[4] These are all in addition to the customer incentive costs already discussed.

III. Results of PG&E's Cost-Effectiveness Test Indicate the Program Is Not Cost Effective

PG&E states that it evaluated its direct load control program under the Commission's traditional total resource cost (TRC) test. It reports that under its base case analysis—that assumes the utility needs new capacity[5] in 2011—the TRC test results in a benefit cost ratio of [redacted] %. PG&E also ran its TRC test under an alternative scenario that assumed that the utility needs capacity immediately—thus, providing a capacity value based on a new combustion turbine (net of energy benefits) in each year of the analysis. Under this scenario, the direct load control program reached a [redacted] % benefit cost ratio—still not cost effective.

1. PG&E Really Used the Program Administrator Test

Although PG&E spends a chapter discussing and describing the characteristics it used in its total resource cost (TRC) test, a detailed evaluation of PG&E's cost-effectiveness workpapers reveals that PG&E's cost-effectiveness test more closely resembles the program administrator cost (PAC) test—not the TRC. TURN makes this claim because PG&E included all of its proposed customer incentives as costs in its cost-effectiveness test. The Total Resource Cost test does not classify customer incentives as a program cost. The TRC test classifies customer incentives as "transfer payments" between participants and non-participants—which excludes consideration of customer incentives altogether. Thus, instead of evaluating its program using the TRC, PG&E evaluated its direct load control program using the program administrator test.

[5] Under PG&E's base case scenario, new capacity is not needed until 2011, when the value of capacity is based on the costs of a new combustion turbine (net of energy savings). Under this scenario, the years 2007-2010 assume the value of capacity is based on an existing steam turbine—that ranges in value from approximately 7% to 18% of the cost of a new combustion turbine.

TURN believes that it is useful for the Commission to have full knowledge of a demand response or energy efficiency program under all of the cost-effectiveness tests contained in the standard practice manual (SPM) and PG&E's analysis does provide useful, albeit a more conservative, information for evaluating the program. However, it is not a TRC test as reported by PG&E.

Excluding customer incentives from the cost-effectiveness analysis and running PG&E's program through a standard TRC test marginally improves the test results ([redacted]) but still does not result in a program that is cost-effective. However, these cost-effectiveness results use an inappropriate discount rate (discussed below). Using the appropriate discount rate and using the TRC framework the cost-effectiveness of PG&E's proposed program only marginally improves to [redacted].

B. Use of the Appropriate Discount Rate For PG&E's Total Resource Cost Test

PG&E's analysis uses an after tax weighted average cost of capital (ATWACC) of 7.60%. TURN recommends a higher discount rate based on PG&E's weighted average cost of capital of 8.78%. The difference between PG&E and TURN is that the tax deductibility of bond interest is included in PG&E's calculation. The Commission has, for about 20 years, used the utility's cost of capital without tax effects as a discount rate for many of its economic evaluations, including calculation of combustion turbine costs for avoided capacity cost; new supply and transmission options such as the California-Oregon Transmission project and Palo Verde-Devers #2, and the calculation of marginal distribution costs for rate design by PG&E and Edison. In this case, PG&E has brought forward a lower discount rate that increases alleged benefits of direct load control by somewhere between 10 and 13% by assigning more weight to the distant future than to the near term.

TURN believes that a more consistent and accurate estimation of benefits relative to costs can be obtained by using the utility's cost of capital. When ratepayers pay for this direct load control program, they will pay rates that include the utility's full cost of capital (plus income and property taxes). Including a tax deduction for bond interest has no basis in economic reality or ratemaking, since ratepayers pay the full bond interest rate and even pay extra taxes on equity in the revenue requirements that will cover the direct load control program. To use a lower discount rate than the actual amount that ratepayers must pay distorts the economic position of ratepayers and artificially inflates the future benefits of direct load control.

IV. Redesigning PG&E's Direct Load Control Program to Achieve Positive Cost Effectiveness

TURN is somewhat perplexed that despite designing a program so poorly, PG&E now requests that the Commission authorize this poorly designed program—despite the fact that the utility itself indicates that the benefits of the program will never be greater than program costs.[6] If this were the only choice the Commission had (adopt as proposed or do not adopt as proposed) then TURN would recommend that the Commission summarily reject PG&E's request.

However, by changing the program design without substantially changing PG&E's assumed costs and/or benefits the program can provide positive benefits to PG&E's ratepayers and result in a TRC cost-effectiveness

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[6] The TRC test does not recognize customer incentives as a cost, but instead treats them as a transfer payment. Thus, PG&E's analysis does not account for customer incentive costs that PG&E assumes will increase program costs by a little over $60 million on a NPV basis (2007-2030).

score that is sufficiently robust to provide the Commission confidence that it is a good program for ratepayers to fund. [7]

In this testimony, we demonstrate that with a number of adjustments the program can become cost-effective under the TRC and can provide net benefits to ratepayers. However, to actually achieve a positive program cost effectiveness, it will be necessary for the Commission to accept all of TURN's recommendations to ensure benefits are positive by a sufficient enough margin to provide confidence that the program is a good investment for ratepayers. TURN's TRC cost-effectiveness results (as well as those we report for PG&E) are reported on a benefit ratio basis and assume a) customer incentives are treated as transfer payments and b) use of PG&E's before tax WACC as the discount rate.

A summary of TURN's recommended adjustments include the following:

- Limit the program to only residential customers;
- Exclude PCTs and limit the direct load control equipment to only air conditioner cycling Switches;
- Prohibit customers from participating simultaneously in both critical peak price (CPP) tariffs and direct load control,
- Reject PG&E's proposed risk contingency allowance;
- Redesign the program tariff to allow for direct load control during weekends and not just weekdays as proposed by PG&E.

Adopting these recommendations will provide that the program is sufficiently cost-effective as evaluated using the TRC framework. However, if the

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[7] In a data request to PG&E, TURN requested that PG&E run its TRC model using a number of alternative scenarios. PG&E refused to those scenarios for TURN insisting that the request of overly broad and burdensome. However, PG&E did run alternative scenarios (on the same model) for the Division of Ratepayer Advocates (DRA data request #2-4). Thus, TURN is in the uncomfortable position in this proceeding of having to manipulate PG&E's model to obtain TRC score results based on a number of TURN recommended alternative scenarios. While TURN is confident that its TRC score results are "in the ballpark" a more comprehensive and accurate result would have been for PG&E to run its OWN model and provide those results to all intervenors—not just the intervenors favored by PG&E.

Commission decides that a more conservative cost-effectiveness framework such as the PAT is necessary, then TURN believes that it will be necessary to either a) delay the program or b) ramp the program implementation more slowly so that it more closely coincides with PG&E's actual need for new capacity resources. Further, deferring the program also may provide additional benefits to PG&E's ratepayers because it may then be able to coordinate this program with PG&E's advanced metering infrastructure (AMI) deployment—that according to PG&E's latest AMI report may be deferred due to the utility reevaluating its original technology choice.

In the alternative, if the Commission rejects TURN's recommendations to redesign PG&E's program, TURN recommends that the Commission require PG&E to issue a new RFP for a direct load control program. In issuing that RFP the Commission should direct the utility to either require certain minimum cost and functionality thresholds that would ensure that the winner of that RFP provides the utility with a cost-effective load control program or direct the utility to completely bid out program to an independent third- party installer and/or implementer that would provide that product to PG&E on a long-term $/kw-yr contractual basis.

1. Limit the Program to Only Residential Customers

PG&E proposes to offer its direct load control program to residential customers, and small commercial customers divided into those with loads a) less than 20 kW and b) between 20 kW and 200 kW. PG&E analysis assumes that 15% of total program participants will be commercial customers with a 90%/10% split between small commercial and large commercial customers. TURN opposes this recommendation and suggests that the program should be limited entirely to residential customers because the incremental demand response from small commercial customers is not worth the significantly greater per unit program cost associated with commercial customers.[8] Further, PG&E's August 31st Report on its 2007 load control program reports that it's commercial customers have shown little interest in the program.

PG&E's Table 4-3 shows that PG&E assumes that, before further adjustments, residential PCTs and Switches will both provide a 1.10 kW average hourly demand reduction. Small commercial customers (< 20 kW) are assumed to provide a 0.88 kW/unit load reduction from PCTs and a 1.12 kW/unit load reduction from Switches—less than, or equal, to that provided by residential customers. Larger commercial (20 kW – 200 kW) customers are assumed to provide 1.54 kW and (PCTs) and 1.96 kW (Switches) average hourly demand reductions—a small demand reduction relative to those customers' average demand and in the range that Southern California Edison assumes is the average demand response from its residential air conditioner cycling program.[9]

While the load impact per unit from small commercial customers is less than or equal to that of residential customers, the per unit costs of acquiring and installing load control devices for small commercial customers are substantially greater than the costs for residential customers. The price of a small commercial Switch is $[redacted] compared to the cost of a residential Switch of $[redacted]. PG&E also assumes that the cost for acquiring a residential customer in the program is $[redacted] while acquiring a small commercial customer is double that cost-- $[redacted]. Finally, PG&E states that it may provide up to $50/unit installation bonus per residential customer while providing up to $100/unit installation

[8] While TURN acknowledges that Table 4-3 shows a larger kW impact from customers between 20 kW and 200 kW, PG&E's proposal only targets a limited 6,000 customers or 1.5% of total participants. Thus, the impact on the total program is extremely limited.

[9] "SCE's Report on Its Interruptible and Demand Response Programs for July 2007, Table I-1". TURN is aware that the higher average demand response assumed by SCE is due to differing assumptions concerning cycling strategies (PG&E, Chapter 4, p. 4-5). Also, SCE's Interruptible Report shows higher average demand response in Table I-1 than that reported by PG&E on p. 4-5.

bonus to small commercial customers.[10] Thus, PG&E plans on spending over 70% more per small commercial as it would spend on a residential customer—**for less demand response.** This is poor program design and one of the reasons that the program, as designed by PG&E, is not cost-effective

The other reason for not including small commercial customers in this program is the apparent lack of interest in such a program based on data from the current 2007 direct load control program. By June 2007, small commercial customers as a percentage of total PCT and Switch installations were only 0.78% of the total number of installations (63 out of 8,087 participants were small commercial).

PG&E's August 31st Report reaffirms this lack of interest from commercial customers. "PG&E mailed a marketing brochure to 20,000 commercial customers in May and received an insignificant response. Currently, PG&E has 78 commercial customers on the program." (p. 8).

Thus, given the lack of interest from small commercial customers, the significantly greater cost for their program participation, and the fact some of these customers would actually provide less demand response per unit compared to residential participants, TURN believes it makes little sense to include these customers in PG&E's proposed direct load control program.

B. Limit the Load Control Technology to Only Air Conditioner Switches

PG&E's cost-effectiveness analysis assumes that 60% of its customers will choose a PCT over an air conditioner Switch. PG&E also assumes that residential customers that choose a PCT over an AC Switch will provide the same 1.10 kW/per unit demand reduction (before other PG&E adjustments) as that

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[10] TURN is aware that PG&E does not initially plan on providing this level of incentive to customers. However, it appears fairly certain from PG&E's filing that the installation bonus for small commercial customers will be double what is provided to residential customers.

provided by a Switch. However, the cost of a residential PCT ($[redacted]) is 236% more expensive than a Switch ($[redacted]) before installation. In addition, installation for a PCT is assumed to be 22% more expensive[11] for ($[redacted]) than a Switch *installation* ($[redacted]). There is no reason to spend $[redacted] to achieve the same level of demand response impact that can also be obtained by spending $[redacted]. While PCTs may be the "fashion" in California's current regulatory circles—it simply make no sense to spend ratepayer on a "fashionable widget" when the "unfashionable widget" provides the same level of demand response for a fraction of the price.

PG&E's analysis assumes that 60% of its residential and C&I load control participants will choose a PCT over a Switch (PG&E, p. 4-9). This assumption was reached as a result of a consultant report that surveyed customer preferences for load control devices.[12] Interestingly, the results of that consultant directly conflict with empirical evidence resulting from implementing PG&E's 2007 load control program that also provides customers the choice between an air conditioner Switch and a PCT.

As of June 2007, PG&E had enrolled a total of 8,087 residential and C&I customers in its current 2007 direct load control program. Approximately 65% of the total program participants chose a Switch over a PCT with approximately 65% of the residential participants picking the Switch and 63% of C&I program participants picking the Switch.

In its August 31, 2007 Report to the Commission on the status of its 2007 direct load control program, PG&E reports an even larger percentage of

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[11] TURN is somewhat doubtful that PG&E's assumptions on PCT installation costs are accurate compared to the Switch installation costs—because scheduling and installing a Switch is relatively uncomplicated compared to a PCT. PG&E also questions its original installation assumptions and has found "that actual costs for the installation of the devices are greater than originally estimated". (August 31st Report, p. 5).

[12] Customer Preference Research on Direct Load Control; Momentum Group, June 2005; p. 20.

customers that have installed Switches relative to PCTs. Of the 8,341 load control devices installed by the end of August 2007, 72% of those devices were installed Switches (5,988) while PCTs accounted for 28% of the installed load control devices. Thus, PG&E's assumptions that 60% of its customers will choose PCTs over Switches is contradicted by the empirical evidence of its current 2007 load control program.

1. Technical Difficulties With PCTs Provides Additional Rationale To Limit the Program to Switches Only

PG&E's August 31 2007 Report on its direct load control program reveals technical difficulties with PCTs that provides an additional reason why the program should be limited to AC Switches only.

> "PG&E has discovered that when the thermostat is set back, the air conditioner fans cease to circulate. <u>PG&E might conclude that cycling the thermostats similar to cycling the switches might be a preferable alternative</u>." (PG&E August 31, 2007 Report on its Direct Load Control Program, p. 4, emphasis added).

This is an important discovery on the part of PG&E and provides additional support to TURN's recommendation to limit the program to only AC Switches. In addition to providing virtually equivalent demand response on a per residential unit basis (for over 3 times the cost), now it's seems apparent from PG&E's discovery that PCTs could simply be operated in an identical manner as AC Switches (i.e., cycling the unit off for some period of time) while a) costing substantially more than an AC Switch and b) being less popular with customers than Switches.

Based on PG&E's TRC model, limiting the program to only residential customers and only air conditioner cycling Switches increases the cost effectiveness relative to PG&E's base case scenario (using TURN's recommended discount rate) to benefits being [redacted]% of total costs—compared to PG&E's [redacted]% of total benefits to total costs.

C. Prohibit Participants in PG&E's Direct Load Control Program From Taking Service Under Critical Peak Pricing Tariffs

PG&E proposes to allow customers participating in its direct load control program to also take service under critical peak pricing (CPP) tariffs. PG&E assumes that 30% of its residential program participants will also take service under CPP rates and 18% of its C&I program participants will take service under CPP.[13] This is a large detriment to this program's cost effectiveness.

PG&E's Table 4-3 shows that PG&E assumes (before adjustments) a 1.10 kW/per unit reduction for residential Switches and PCTs. PG&E then adjusted these demand response estimates downward to reflect its assumptions concerning a) technical malfunction rates (0.5%), b) technology disconnection rates (2.0%), and customer overrides of events (8.0%). This roughly adjusts the demand response from both Switches and PCTs to approximately 1.0 kW/per unit.[14]

After having made these adjustments to its assumptions concerning average demand response per customer PG&E then makes a final adjustment downward to account for the demand response attributed to a) only direct load control participants and b) direct load control participants also served under critical peak pricing tariffs.

According to PG&E's analysis, a residential customer that only participates in the direct load control program will provide approximately 1.0 kW/unit reduction during and event. However, if that same residential customer also takes service under a CPP tariff, only 0.17 kW/unit will be associated with

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[13] Because TURN proposes to limit this program to only residential customers, a discussion of the affects of CPP on C&I customers is not contained in this testimony.

[14] PG&E forecasts a 2.0% disconnection rate for Switches resulting from AC maintenance or replacement. Thus, PG&E's analysis assumes that Switches will provide 2% less demand response from AC Switches than from PCTs before further adjustments for CPP overlap. The difference is not material.

the direct load control device. This seriously dilutes the demand response savings from the direct load control program—so that on a weighted average basis, PG&E assumes a 0.75 kW/per unit demand response from its total direct load control program.

Indeed, under PG&E's proposal, PG&E would spend (on average) over $[redacted]/unit to install a Switch that would obtain approximately 1.0 kW/per unit (for customers not participating in CPP) while also spending that same $[redacted]/per unit for a dual participating customer and obtain 0.17 kW/per unit.

Allowing CPP and direct load control overlap dilutes total average demand response by almost 25%. **Design the program to eliminate this overlap and the program could obtain an additional 70 MW of demand response for no additional cost**. TURN strongly recommends that the CPUC pick this "low hanging fruit" that also has a material effect on the cost-effectiveness of the program.

D. Eliminate PG&E's Risk Contingency

PG&E's application requests that the Commission authorize over $19.4 million in a "risk contingency" fund. TURN opposes PG&E's request. The Company has not met its burden of proof in explaining why it is necessary to receive a risk contingency—especially given PG&E's statement that if it does need additional program funding it may seek that additional funding from the Commission (PG&E, p. 7-9). In addition, if the Commission adopts TURN's recommendations on redesigning this program many of these "risks" will be substantially reduced or eliminated.

PG&E explains its need for $19.4 million in risk contingency in a single sentence;

> "Most of the costs associated with the risk-based contingency allowance are related to additional information technology needs or material cost increases" (PG&E, p. 7-9).

That's it in a nutshell. One sentence, $19.4 million charge to ratepayers.

However, this one sentence description seems at odds with the workpapers describing what the risk contingency is being applied to. Approximately [redacted]% of that risk contingency is associated with vendor responsibilities. Thus, instead of entering into contracts designed to shift risk onto vendors, PG&E the Commission to shift the risk of overruns or project failure from the vendors to PG&E's ratepayers.

Of the remaining [redacted]% of that contingency over [redacted]% of that money is to mitigate PG&E's risk of integrating this program into its various Information Technology (IT) systems. Indeed, PG&E is so uncertain of its ability to do this in an efficient manner it asks for a 50% contingency risk factor for integrating this program with its IT system—an IT system that has been one of PG&E's long standing banes.

PG&E does describe a number of risks that are not contained in the risk allowance (PG&E, p. 7-9)—a) that customers will choose the more expensive PCT technology than forecast by PG&E and b) there is a larger CPP and program overlap (requiring PG&E to subscribe more customers for the same amount of forecast MWs). If the Commission adopts TURN's recommendations then both of these risk contingencies are eliminated.

Finally, authorizing PG&E's risk contingency allowance implies that the utility is willing to fund this program at its currently requested funding level and that a) the risk allowance will compensate the utility for any cost overruns and b) it will not request additional funding if there are cost overruns. However, this is not the case. As PG&E's states in its testimony:

> "In the event that PG&E's forecast prove to inaccurate and PG&E requires additional funding to achieve the demand response goals, PG&E will advise the Commission and proceed according to Commission direction" (PG&E, p. 7-9).

PG&E admits that it is not committing to this level of funding and reserves the right to request additional program funds. Given all these reasons, the Commission should reject PG&E's request for its "risk contingency allowance".

E. Expand Dispatch Criteria to Allow The Program To Be Called On Weekends

PG&E's program limits dispatch to only weekdays. TURN recommends that the program be designed to allow for events to be called during weekends as well. PG&E's proposal to limit the calling of events to weekdays may reduce the ability of this program to provide valuable demand response when it might be most needed.

The heat storm that occurred during the Summer of 2006 did not limit itself to weekdays. The summer of 2006 heat storm lasted from July 15th to July 28th. During that heat storm, the residential class actually experienced its highest peak demand during the July 22-23 weekend. Saturday the 22nd, the residential class had its second highest heat storm average peak of 8,531 MW and on the following Sunday hit an even higher average peak of 8,797 MW.[15]

TURN notes that the residential direct load control programs of both Southern California Edison (Edison) and San Diego Gas and Electric (SDG&E) provide for cycling events that occur on weekends. Edison's program has no restrictions concerning weekend events and SDG&E's program provides customers with the choice of being cycled during only weekdays (5 day option)

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[15] The hourly residential peak actually hit 9,275 MW during the 4 pm hour on Sunday July 23rd 2006.

or any day (the 7 day options). The Sacramento Municipal Utility District's (SMUD) "Peak Corp" residential air conditioner cycling program also contains no weekend restrictions for calling cycling events. Thus, TURN recommends that the Commission alter PG&E's proposed design of this direct load control program to life the prohibition of calling a cycling event during summer weekends.

F. TURN's Proposed Program Design Results In A Cost Effective Program Under the Total Resource Cost Test

Each of TURN's proposed changes to PG&E's direct load control program increase the TRC cost-effectiveness of this program relative to PG&E's proposed program design. All results assume that a) customer incentives are treated as transfer payments and b) the discount rate is based on PG&E's before-tax weighted average cost of capital (8.78%). Each resulting score is cumulative (i.e., Only residential Switches and no contingency = 102% benefit cost ratio). The effect of TURN's recommendations on the program's Total Resource cost-effectiveness are reported in Table 1.

Table 1

Scenario	**TRC Benefit Cost Ratio**
PG&E Base Case	0.76%
Residential Switches Only	94%
No Contingency	102%
No CPP Overlap	126%

As Table 1 reports, PG&E's proposed direct load control can be redesigned to achieve a positive benefit cost ratio. However, the Commission must a) limit the program to only residential Switches, b) exclude the overlap between CPP and direct load control participants, and c) reject PG&E's proposed contingency allowance to ensure confidence that ratepayers pay for a program that provides them with a sufficient level of net benefits.

G. Cost Effectiveness Of TURN's Recommended Program Adjustments Using the Program Administrator Test

PG&E's cost-effectiveness analysis more closely resembles the Program Administrator Test (PAT) than the TRC test because customer incentives are treated as a cost instead of a transfer payment. This causes PG&E's analysis to be more conservative on a rate impact basis than it would be using a TRC framework. TURN does not oppose PG&E's use of the PAT and has stated, in the recent rulemaking addressing the framework for evaluating the cost effectiveness of demand response programs (R. 07-01-041), that it is important for the Commission to have a full record of a demand response program test results under all of the Standard Practice Manual's (SPM) defined cost-effectiveness tests.

Evaluating PG&E's proposed direct load control program under a PAT framework inherently reduces the program's cost effectiveness (relative to the TRC) because customer incentives layer an additional cost onto the program. Because of this, it is even more important for the Commission to adopt all of TURN's recommendations on increasing the cost effectiveness of the program because all of the adjustments are necessary for the program to achieve net benefits for ratepayers under the PAT. Results using the PAT are reported in Table 2 in the same manner that they were reported for the TRC results reported in Table 1.

Table 2

Scenario	PAT Benefits Cost Ratio
PG&E	66%
Residential Switches Only	83%
No Contingency	88%
No CPP Overlap	109%

As shown in Table 1, under the PAT PG&E's proposed direct load control program provides net benefits only if all of TURN's recommendations are adopted. While this analysis shows net benefits, if the Commission decides that these net benefits not provide sufficient confidence for a program of this length, it may consider additional adjustments to the program, such as either deferring the program or ramping it more slowly than PG&E has proposed. Two additional benefits would result from this.

First, the Commission's Long Term Procurement Plan (LTPP) proceeding, PG&E does not forecast that it will need new capacity either 2011 or 2012 (PG&E, Chapter 6, p. 6-2). In that same proceeding, TURN found that PG&E does not need new capacity resources until 2014 (R.06-02-013). Thus, the utility has no need to rush implementation of this resource and has the luxury of time to "get it right". While PG&E had optimistically forecast that it would obtain 25 MW of direct load control in 2007, it is not close to achieving that goal. Thus, PG&E's inability to meet its forecast implementation goals actually end up benefiting ratepayers relative to PG&E's current forecast.

H. This Direct Load Control Program May Benefit From PG&E's Current Re-Evaluation Of It's Authorized AMI Technology

It may be an enormous waste of resources for the Commission to approve this program as designed at this time, without assessing whether the program could benefit from the fact that PG&E is reassessing it's authorized AMI technology. As designed, the direct load control program does not really benefit from PG&E's multi-billion dollar investment in AMI. At this point, PG&E's AMI project will simply be used as a form of load profiling meter that then provides the utility (actually a consultant will be hired) to create an algorithm to identify sites that are not responding to event curtailment signals (PG&E, p. 5-9). This is not a materially different method from how these programs have been evaluated over the last twenty years. a

However, despite authorizing an AMI system that did not integrate load control capability into its network, the Commission may have "another bite at the apple" because PG&E is currently re-evaluating its AMI technology.

In its recent report to the Commission on the status of its AMI deployment, PG&E has reported that it is re-evaluating its authorized AMI project.

> "Based on these advancements, PG&E is analyzing estimated costs and potential benefits of incorporating new technology into its current SmartMeter Program to develop the business case for the potential implementation of:
>
> - Solid state meters with integrated disconnect switches;
> - Real-time energy devices that will enable HAN technologies, and
> - Network upgrades using RF mesh technologies." [16]

Given that PG&E is admits that it is going back to the drawing board to assess whether it has actually picked the optimum AMI technology, it is a more than opportune time for the Commission to coordinate that process with PG&E's current proposal to implement a direct load control program.

[16] PG&E Advanced Metering Infrastructure July 2007 Semi-Annual Assessment Report, July 20, 2007, p. 6.

TURN notes that Southern California Edison's current application for approval of its AMI deployment includes a discussion of how it intends to integrate load control technology with its overall AMI deployment. That discussion is included as Attachment B, and describes an integration of AMI and load control technology that is considerably more sophisticated than what is envisioned by PG&E and its AMI system.

I. Conclusions

PG&E's proposed load control program is not cost-effective as filed by the utility under either the total resource cost test or the program administrator test. However, the program can be designed to provide positive net benefits (under either of these tests) for PG&E's ratepayers if it a) is limited to only residential customers with air conditioner Switches, b) does not overlap with CPP, and c) does not include PG&E's risk contingency.

While PG&E proposes to immediately implement a program that ramps up by 100 MW per year for 2008-2010, the Commission should consider either deferring or ramping the program up more slowly to more accurately coincide with PG&E's need for new capacity. Finally, and importantly, the Commission should also consider whether ratepayer benefits from this load control program can be significantly increased by coordinating this application and program with PG&E's current re-evaluation of its authorized multi-billion dollar AMI project.

Attachment A Qualifications of Jeffrey A. Nahigian

Jeffrey Nahigian, a Senior Economist, has over 18 years experience analyzing utility operations and rate design issues.

He received a B.S. in Environmental Policy Analysis and Planning from the University of California, Davis, in 1986. He also holds a B.Mus. degree from the San Francisco Conservatory of Music. In 1986, Mr. Nahigian joined JBS Energy.

Mr. Nahigian has analyzed cost-of-service and rate design issues in California, Nevada, Arkansas and Alberta including review of marginal and embedded electric and gas distribution and customer costs, residential baseline rates, customer charges and time-of-use rates, and interruptible electric rate design. He was a member of the rate unbundling working group for California electric restructuring.

He has 12 years' experience with the analysis of line extension rules in several jurisdictions and of energy and water utility issues affecting mobilehome park tenants.

He has reviewed conservation programs of utilities in Georgia, Texas, and the District of Columbia for prudence in implementation and cost-effectiveness. He wrote a white paper analyzing conservation strategies for targeting large industrial users of natural gas. He has also reviewed the energy efficiency programs of California's four major gas and electric investor owned utilities and evaluated third-party bids for local efficiency programs. He is currently involved in the evaluation of advanced meter deployment in California and has been a featured speaker on this topic for various national and international utility and metering conferences.

He has reviewed avoided cost methodology and policies for several clients, calculated emissions and emissions values from utility power plants, and reviewed nuclear power plant performance and costs. Mr. Nahigian was the lead analyst for a comparative study of the costs of San Diego Gas and Electric (SDG&E) and other California utilities. He served on an advisory committee to the California Energy Commission on transmission policy under Senate Bill 2431.

Mr. Nahigian was manager of two projects analyzing the Rancho Seco nuclear plant and alternatives to it. He was an alternate member of the SMUD Rate Advisory Committee in 1990-91.

Mr. Nahigian has testified at the California Energy Commission on conservation policy and technical issues, nuclear plant performance, forecasts of future Qualifying Facility (QF) projects, municipal utility demand conformance, and the economics of returning mothballed fossil plants to service. He has filed testimony and formal comments at the California Public Utilities Commission on electric and gas cost of service and rate design; line extension issues, adjustments of gas load forecasts for energy efficiency; utility distribution capital spending; water rates for mobilehome parks, and SDG&E's fuel budget. He provided expert testimony before the Los Angeles County Superior Court on electric rates for mobilehome parks and before the Alberta Energy and Utilities Board on line extension policy.

Before joining JBS, Mr. Nahigian was a staff analyst for the California Independent Energy Producers Association in 1986

CERTIFICATE OF SERVICE

I, Larry Wong, certify under penalty of perjury under the laws of the State of California that the following is true and correct:

On November 6, 2007 I served the attached:

MOTION OF THE UTILITY REFORM NETWORK FOR ADMISSION OF ITS LATE-FILED TESTIMONY INTO EVIDENCE

on all eligible parties on the attached lists to **A.07-04-009**, by sending said document by electronic mail to each of the parties via electronic mail, as reflected on the attached Service List.

Executed this November 6, 2007, at San Francisco, California.

_____/S/__________

Larry Wong

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